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Volatile Oils And Retrograde Gases–What's The Difference?

Part 3: In a continuing effort to describe the five different reservoir fluids, this segment of the series will explain the differences between volatile oils and retrograde gases. An initial producing gas-oil ratio of 3,200 scf/STB and a heptanes plus composition of 12.5 mole % appear to be good separation points between these fluids.

Part 1 showed that at reservoir conditions, volatile oils exhibit bubble points and retrograde gases exhibit dew points.[1] The article contained a graph of initial producing gas-oil ratio plotted against concentration of heptanes plus in the fluid. Fig. 1 is a portion of that graph with the data points indicating that the fluid had a dew point or a bubble point at reservoir conditions. The scatter in the data reflects the compositional differences among the fluids and the differences in surface separation facilities and conditions.

In Fig. 1, only three fluids have dew points at initial producing gas-oil ratios less than 3,200 scf/STB, and only one fluid reaches a bubble point above this value. Therefore, a value of 3,200 scf/STB appears to be a good cutoff between volatile oils and retrograde gases.

Only two fluids with heptanes plus compositions less than 12.5 mole % exhibit bubble points, and only three fluids with concentrations above this value exhibit dew points. Thus, 12.5 mole % heptanes plus is a useful dividing line between volatile oils and retrograde gases. Actually, heptanes plus content has been observed as low as 10 mole % in volatile oils and as high as 15 mole % in retrograde gases.[2] These cases are rare and often involve unusually high stock-tank oil gravities.

Retrograde behavior has been observed in laboratory studies of retrograde gases with initial gas-oil ratios over 150,000 scf/STB, although the amount of retrograde liquid is small (less than 1% of the reservoir pore space). Apparently, most gases that release condensate at the surface probably release some condensate in the reservoir—probably very few true wet gases exist. However, wet gas theory can be applied to retrograde gases that release small amounts of liquid in the reservoir. This will be explored in Part 4 of this series.

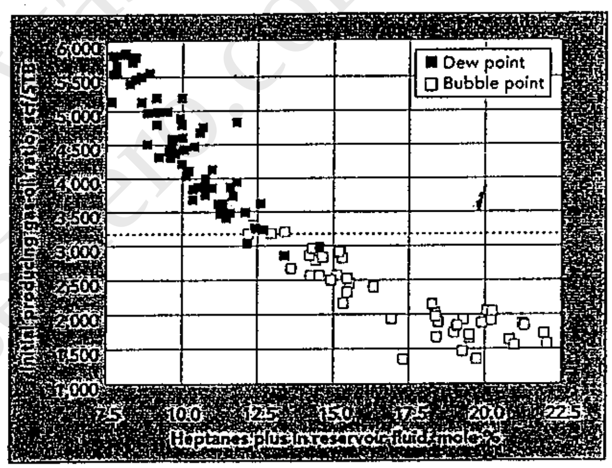

Fig. 1. Initial gas-oil ratios of 3,200 scf/STB and 12.5 mole % heptanes plus in the reservoir fluid are good cutoffs between volatile oils and retrograde gases.

Fluid Permeabilities

The retrograde liquid formed in a retrograde gas reservoir at pressures below the dew point of the gas is virtually immobile. Fig. 2 shows the oil and gas relative permeabilities of a reservoir containing a retrograde gas. The condensate in the reservoir is considered the wetting phase, so these relative permeabilities were measured in an imbibition process. Irreducible water saturation was present at 25 volume %.

The use of Fig. 2 requires an estimate of the highest possible condensate saturation. Phase diagrams presented in Part 1 of this series show that the 50-volume % liquid line is almost vertical just below the critical points of the typical volatile oil and all three typical gases. Generally, this is true and shows that the maximum possible condensate saturation in a retrograde gas is 50% of the hydrocarbon pore space. Of course, only the richest retrograde gases, with critical temperatures very near reservoir temperature, release this much retrograde liquid. Therefore, the total liquid saturation of the reservoir represented by Fig. 2 will start at an irreducible water saturation of 0.25 and build to a maximum of 0.625 as pressure declines. Obviously, the effective permeability

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to the condensate is almost zero throughout most of this range. Little production of the retrograde liquid occurs as the reservoir is depleted.

Fig. 2 also depicts the rapid decrease in effective permeability to gas as total liquid saturation increases. Effective permeability to the nonwetting phase is much more affected by increases in the wetting phase saturation of an imbibition process than in a drainage process. Many operators notice a sharp decrease in the gas production rate soon after reservoir pressure passes through the retrograde gas' dew point pressure.

Fig. 2 may not explain the whole story. Flow visualization research at Heriot-Watt University in Scotland, using high-pressure glass micromodels and core flooding with gases and retrograde liquids, shows that these fluids exhibit effective permeabilities that are sensitive to flow rate.[3] The condensate will not flow at low gas flow rates found throughout most of the reservoir. But it does flow at high gas flow rates near the well bores. Although the condensate does not flow with the gas in the main part of the reservoir, it will drain downward due to gravity forces if the reservoir does not contain barriers to vertical flow. Apparently, flow rate sensitivity has not been observed in conventional effective permeability measurements.

Even though the flow stream from the reservoir is virtually all gas, the surface producing gas-oil ratio will increase after the reservoir pressure declines below the dew point. This is due to the loss of condensate (that would have ended up in the stock tank) in the reservoir. The gravity of the stock-tank liquid increases as reservoir pressure decreases because the retrograde behavior in the reservoir removes some of the heaviest components from the gas. These components do not get to the stock tank, and consequently, the stock tank liquid is lighter (higher API gravity).

Special procedures for retrograde gases provide data suitable for predicting retrograde gas reservoir performance. Compositional material balance calculations, with K-factors or equations-of-state, also can be used for future performance prediction. The results of laboratory procedures are necessary for "tuning" the equation-of-state.

Conventional gas material balance equations can be used at pressures above the dew point if the equivalent gaseous volume of the surface condensate is added to the produced gas and if the surface condensate and gas are combined by calculation to determine the properties of the reservoir gas.[4] At pressures below the dew point, the gas material balance equation is applicable if two-phase z-factors are employed to calculate the gas formation volume factors.[5,6] An interesting correlation calculates the compositions of the reservoir gas at pressures below the bubble point.[7]

Part 2 of this series set a maximum initial producing gas-oil ratio of 1,750 scf/STB for black oils.[8] Values of heptanes plus concentrations between 19 mole % and 22 mole % correspond to this ratio. So 20 mole % is a reasonable cutoff between volatile oils and black oils. ●

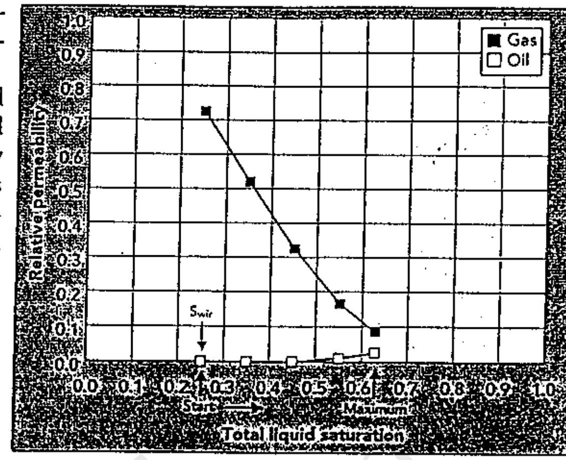

Fig. 2. Very little retrograde liquid production occurs over the range of possible total liquid saturation.

Author's Note

Next month, Part 4 will examine the differences among retrograde gases, wet gases and dry gases.

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